IN THE MATTER OF:	*	**BEFORE THE MARYLAND**
CONSTELLATION POWER	*	**DEPARTMENT OF**
SOURCE GENERATION, INC.	*	**THE ENVIRONMENT**

* * * * * * * * * * * * * *

CONSENT ORDER

This CONSENT ORDER is issued pursuant to the authority vested in the Maryland Department of the Environment ("Department") by Titles 1, 2 and 6 of the Environment Article of the Maryland Code and by the Code of Maryland Regulations (COMAR) 26.11 to regulate air pollution in the State of Maryland and to enforce State air pollution control laws and regulations.

WHEREAS, Constellation Power Source Generation, Inc. ("Constellation") owns and operates the electric generating units identified in Exhibit A of this Consent Order;

WHEREAS, each of the electric generating units identified in Exhibt A is a major source of nitrogen oxides (NOx) and is subject to regulations promulgated by the Department and codified in COMAR 26.11.09.08, which require affected sources to install reasonably available control technology (RACT);

WHEREAS, COMAR 26.11.09.08 establishes emissions standards and other requirements for major NOx sources and contains a provision that allows affected sources that own and operate two or more affected units to comply with NOx emission standards through use of an averaging plan;

WHEREAS, the averaging plan must identify the units that will participate in the plan and include a demonstration that total NOx emissions from the participating units on each day are less than the total NOx emissions that would result if each affected unit met the applicable emission standard in COMAR 26.11.09.08;

WHEREAS, COMAR 26.11.09.08 requires an averaging plan that is approved by the Department to be submitted to EPA for approval as a revision to the approved State Implementation Plan (SIP);

WHEREAS, to be approved by EPA, the averaging plan must meet all applicable federal requirements, including EPA's Economic Incentive Program and must be the subject of a public hearing held in accordance with applicable State and federal requirements;

WHEREAS, the Department has approved Constellation's proposed averaging plan (the "Averaging Plan"), which is attached as Exhibit B and incorporated by reference into this Consent Order; and

WHEREAS, COMAR 26.11.09.08 requires compliance with the approved Averaging Plan to be determined daily and exceedances of the daily requirement to be reported to the Department on a quarterly basis.

WHEREAS, the Department agrees to submit the Averaging Plan and this Consent Order (and any approved revision to the Averaging Plan) to EPA for approval as a revision to the Maryland SIP. Pursuant to § 2-611 of the Environment Article, until such time as EPA approves this Consent Order and the Averaging Plan, this Consent Order shall constitute a Plan for Compliance with the NOx emission requirements of COMAR 26.11.09.08.

ORDER

NOW, THEREFORE, the Department hereby ORDERS, and Constellation hereby CONSENTS to the following terms and conditions:

1. Upon execution of this Consent Order, Constellation agrees to comply fully with the Averaging Plan approved by the Department and attached as Exhibit B. Constellation further

agrees that in the event it acquires additional electrical generating units in Maryland that are not identified in Exhibit A, no later than 30 days following acquisition of any such unit, it will submit a revised Averaging Plan including the newly acquired units to the Department for approval. Until such time as the Department approves the revised Averaging Plan, any newly acquired electrical generating unit shall be subject to the applicable NOx emission limitation contained in COMAR 26.11.09.08.

2. Constellation agrees that in the event it fails to comply with the Averaging Plan as approved by the Department, the requirements of COMAR 26.11.09.08 shall apply to each of its Maryland electrical generating units.

3. Constellation agrees to timely submit a copy of the quarterly report of exceedances required by COMAR 26.11.09.08 to EPA Region III. All such reports shall be mailed to:

Judith Katz, Director
Air Protection Division
U.S. EPA, Region III
1650 Arch Street
Philadelphia, PA 19103-2029

4. Constellation consents to the inclusion of the approved Averaging Plan and the requirements of this Consent Order into its Title V operating permit.

5. Constellation agrees that nothing in this Consent Order shall be construed to relieve Constellation of its obligations under the Consent Decree executed by Constellation's predecessor in interest, Baltimore, Gas and Electric Company, dated November 11, 1999 relating to Constellation's compliance with Maryland's NOx Budget Rule as codified in COMAR 26.11.27 and .28.

6. The provisions of this Consent Order shall apply to and be binding on Constellation and its successors and assigns, including all transferees of any legal or equitable interest in Constellation's Maryland electric generating units. At least 30 days prior to transfer by Constellation of any legal or equitable interest in Constellation or in any of Constellation's Maryland electric generating units, Constellation shall provide a copy of this Consent Order by means of certified mail to the prospective successor-in-interest. Any agreement for the transfer of any legal or equitable interest in any of Constellation's Maryland electric generating units shall provide that the transferee of such interest shall comply fully with the terms and conditions of this Consent Order, and that the Department may enforce the terms of this Consent Order against the transferee. Constellation shall contemporaneously provide the Department with a copy of the portion(s) of the transfer agreement evidencing its compliance with the terms of this Paragraph.

7. It is the intent of the parties that the provisions of this Consent Order be severable and that, should any provisions be declared by a court of law to be invalid or unenforceable, all other provisions shall remain in effect to the maximum extent reasonable. The parties agree that this Consent Order shall be governed by and construed in accordance with Maryland law.

8. Constellation acknowledges that the Department may seek any legal or equitable remedy available to it for violations of this Consent Order.

CONSTELLATION POWER SOURCE GENERATION, INC.

3/30/01
Date

By: Wayne C [signature]
Title VP-Baltimore Operations, CPSGI

DEPARTMENT OF THE ENVIRONMENT

4/16/01
Date

Ann Marie DeBiase [signature]
Ann Marie DeBiase, Director
Air and Radiation Management Administration

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Approved as to form and legal sufficiency this 5th day of April, 2001.

Kathy M. Kinsey
Assistant Attorney General

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Exhibit A

NO_x RACT affected sources that are participating in the averaging plan are as follows:

Brandon Shores Units 1 and 2

Gould Street Unit 3

H.A. Wagner Units 1, 2, 3 and 4

C.P. Crane Units 1 and 2

Riverside Unit 4

NOx RACT Averaging Plan Proposal

Re-submitted by,

Constellation Power Source Generation, Inc.
November 6, 2000

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Introduction

The purpose of this document is to propose a NOx Reasonably Available Control Technology (RACT) averaging plan that meets the NOx RACT requirement of reducing NOx emissions while allowing Constellation Power Source Generation, Inc. (CPSG) to use the most economical selection of NOx control technologies. EPA has allowed for averaging plants so that more stringent controls can be installed in exchange for lesser controls on others. Specifically the U.S. Environmental Protection Agency (EPA) has addressed NOx RACT averaging in the economic incentive plan (EIP) rule making saying that " an economic incentive plan may allow sources subject to the RACT requirement to attain RACT level emissions reductions in the aggregate"[1]

Environmental Benefit

CPSG's proposed averaging plan will meet the EIP requirements of an environmental benefit by: (1) agreeing to rate based limits that could not be met without an averaging plan and (2) insuring that on an annual basis that the NOx mass emissions from the ten plants included in the averaging plan are at least 5% less than those allowed by the NOx RACT limits. These components of the averaging plan meet the September, 1999 Draft EIP guidance document.[2]

Background

BGE submitted NOx RACT determinations to the Maryland Department of the Environment (Department) on July 1, 1993 for the C.P. Crane Station and on February 15, 1994 for the remainder of the facilities. The recommendations submitted by BGE are included in Appendices "A" and "B"[3]. The Department next issued NOx RACT limits on eight facilities: Brandon Shores Unit 1 & 2,

[1] Federal Register, February 23, 1993, pages 11110 and 11115.
[2] Page 53, Table 5.5(a)
[3] Due to the length of the February 15, 1994 submittal, only the summary is included in Appendix "B"

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Gould Street Unit 3, H.A. Wagner Units 1 through 4, and Riverside Unit 4. These limits are summarized in Table 1.

Table 1
Permit NOx RACT Limits

Station	Unit	RACT, lb/mmbtu
Brandon Shores	1	0.55
	2	0.63
Gould Street	3	0.39
H. A. Wagner	1	0.49
	2	0.70
	3	1.46
	4	0.68
Riverside	4	0.39

These limits were received in Permit to Operate (PTO) permits issued in 1996. In 1998 NOx RACT limits were again revised by the Department to address EPA comments for approving NOx RACT in the State Implementation Plan (SIP). In addition to lowering the limit on several units, limits were put in place for C.P. Crane for the first time. These new limits, effective only from May 1 to September 30, were effective May 1, 2000. They are summarized in Table 2.

Table 2
NOx RACT Limits
May 1 to September 30

Station	Unit	RACT, lb/mmbtu
Brandon Shores	1	0.55
	2	0.60
C.P. Crane	1	0.60
	2	0.60
Gould Street	3	0.39
H. A. Wagner	1	0.49
	2	0.60
	3	0.60
	4	0.60
Riverside	4	0.39

After further discussion with EPA, the Department revised the NOx RACT standards to better reflect existing NOx RACT requirements in other Ozone Transport Region (OTR) states. The new limits are shown in Table 3.

Table 3 Proposed NOx RACT Limits		
Station	Unit	RACT, lb/mmbtu
Brandon Shores	1	0.50
	2	0.50
C.P. Crane	1	0.70 / 1.50*
	2	0.70 / 1.50
Gould Street	3	0.30
H. A. Wagner	1	0.30
	2	0.50
	3	0.60
	4	0.30
Riverside	4	0.30

Affected Units

CPSG's averaging plan would include the following units: Brandon Shores Units 1 & 2, C.P. Crane Units 1&2, Gould Street Unit 3, H.A. Wagner Units 1 through 4, and Riverside Unit 4. Table 4 shows a summary of the NOx emission controls installed by CPSG as of January 1, 2000.

Table 4 Summary of CPSG NOx Controls as of January 1, 2000				
Station	Unit	Controls	Installation Date	Capital Costs
Brandon Shores	1	LNB	Original	-
	1	OFA	1998	$ 3.5 Million
	2	LNB	Original	-
	2	BOOS	1998	$ 0.3 Million
	2	NGR/OFA	1999	$ 4.0 Million
C.P. Crane	1	NGR/OFA	1999	$ 4.5 Million
	2	NGR/OFA	1999	$ 3.0 Million
	C	Gas Pipeline	1999	$ 3.0 Million
Gould Street	3	LNB/Natural Gas	1996	
H. A. Wagner	2	LNB	1995	$ 4.7 Million
	3	LNB/OFA	1999	$ 13.0 Million

LNB – Low NOx Burners
OFA – Over-fire Air
BOOS – Burners Out of Service
NGR – Natural Gas Reburn
C – Common to both Units

* Ozone season limit / Non-ozone season limit

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The following information discusses each unit, the specific NOx controls installed, and their limitations.

Brandon Shores Units 1& 2

Brandon Shores Unit 1 & 2 are coal units with Babcock & Wilcox (B&W) designed, wall-fired, dry bottom boilers, capable of producing 650MW per unit. Each unit's original design included low NOx burners (LNB). These burners allowed for the units to operate approximately 25 % to 30% less than the New Source Performance Standards (NSPS) standard of 0.7 lb/mmbtu. These B&W designed burners were developed early in the B&W Low NOx burner program. Prior to NSPS typical opposed fired wall burners NOx emission ranged from 1.0 to 1.6 lb/mmbtu. B&W earlier designed Dual Register Burners (DRB) achieved NOx emissions between 0.4 lb/mmbtu to 0.7 lb/mmbtu. These burners were called DRB Phase 1. Additional improvements were made to these burners in the 1980's to come up with Phase IV and Phase V DRBs. The Brandon Shores burners are a hybrid model between Phase IV and Phase V. Figure 1 shows the Brandon Shores burners (slide dampers were not included in Brandon Shores original design).

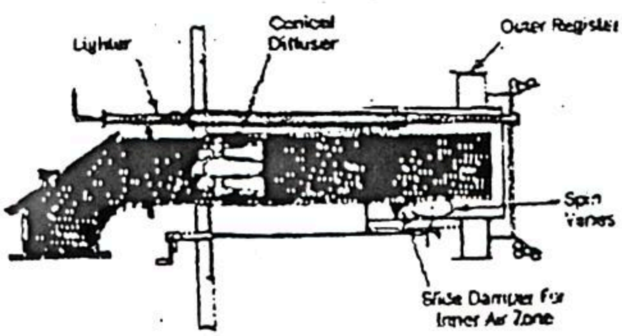

Figure 1

The latest design in low NOx burners, figure 2, shows the major advances in boiler design since the installation of the Brandon Shores burners. The 0.5 lb/mmbtu limit on Brandon Shores is extremely tough to meet with the original burners burning bituminous coal.

Low NO_x Combustion Zones

DRB-XCL™ Type Burner - P. C. Fired

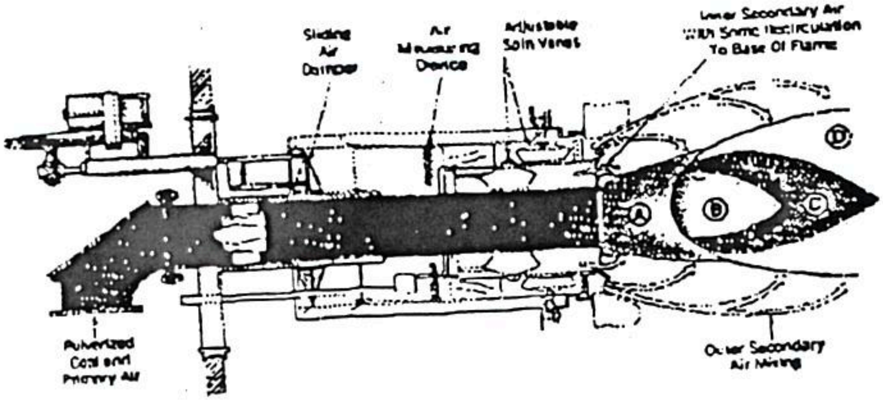

Figure 2

Brandon Shores Unit 1 installed an over-fire air (OFA) system in 1998, while Unit 2's control system was re-configured to allow for operating with a row of burners out of service (BOOS). Both systems achieve a 30% reduction in NOx emissions. One of the major disadvantages of OFA and BOOS has been the increase in unburned carbon and associated heat rate penalty. In a recent study by CPSG's performance group, it was estimated that the heat rate penalty for use of OFA and BOOS for the ozone season only was greater than $ 750,000 dollars a year.[5] In addition to the increased costs for fuel, our on-site carbon separation plant can not process the ash, from Unit 1, during OFA operation. This will reduce ash sales; increases our amount of ash sent for structural fill, and reduce our recycling efforts. This impact is projected to effect over 100,000 tons of coal ash from the Brandon Shores facility.

C.P. Crane Units 1& 2

C.P. Crane Units 1&2 are coal units with B&W designed cyclonc-fired boilers. Each unit can produce up to 200 MW of electricity. C.P. Crane started working on NOx reduction strategies in 1995 with the use of low sulfur content coal, which also reduced NOx emissions by 5% to 7%. The fuel was discontinued after a few months due to expense and handling problems associated with the

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[5] Performance Cost of NOx Compliance, Predictive Maintenance Engineering Unit, BS & CPC Plants. Report No 00-04, February 4, 2000

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coal. In 1999 the boilers were retrofitted with natural gas reburn (NGR) systems to reduce NOx generation by 65%. The NGR system, shown in Figure 3, uses natural gas as the re-burn fuel. The additional fuel expense for using NGR, ozone season only, is approximately 2.3 million dollars. Additional expenses can also occur from boiler wall wastage occurring from the use of the over-fire as part of the NGR system.

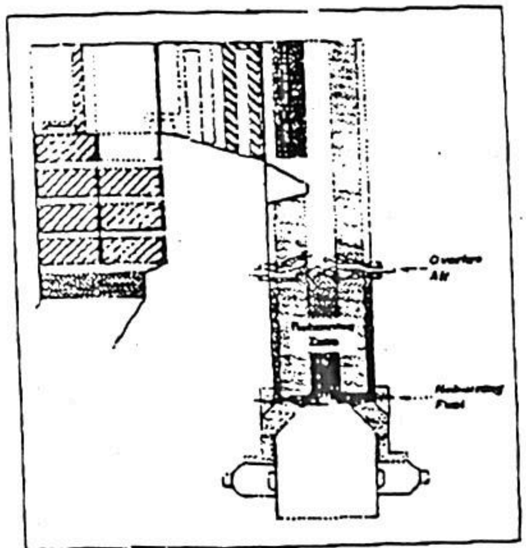

Figure 3

H.A. Wagner Unit 1

H.A. Wagner Unit 1 is a 135 MW B&W designed dual fuel unit capable of firing either natural gas or No. 6 oil. The unit has no additional NOx controls but uses natural gas firing, when economical, to reduce NOx emissions.

H.A. Wagner Unit 2

H.A. Wagner Unit 2 is a 135 MW coal unit with B&W designed front wall burners. Low NOx burners were installed on Unit 2 in 1995 for NOx RACT. The B&W guarantee for these burners was 0.38 lb/mmbtu, but B&W failed to meet this guarantee due to the inability of the pulverizers to produce the required coal fineness. The application of staged (overfire air) combustion for further NOx reduction was not recommended by B&W because the NOx ports cannot be installed on the opposed rear wall for this unit. Installing the NOx ports on the front wall only would create a potential for the poor mixing of the over-fire air with the combustion gases thus resulting in inefficient combustion and significantly higher unburned carbon loss.[6]

H.A. Wagner Unit 3

H.A. Wagner Unit 3 is a 330 MW coal unit originally installed with B&W three-cell burners. Uncontrolled NOx emissions from Wagner 3, prior to 1999, were approximately 1.0 lb/mmbtu. During the spring 1999 outage Wagner 3's boiler was re-built to remove the cell burners and distribute the burners to simulate a wall-fired unit. The existing constraints on Wagner's 3 design limit the changes needed to truly represent a wall-fired burner. The constraints include a limited amount of wall space to split the three cell burners into individual burners. The spacing between burners is crucial to preventing turbulence between burners, which increases NOx production. The lack of wall space is also limited because of residence time constraints so adding additional space beyond the existing boundaries of the cell burners is not acceptable. Figure 4 shows the typical three-cell burner design.

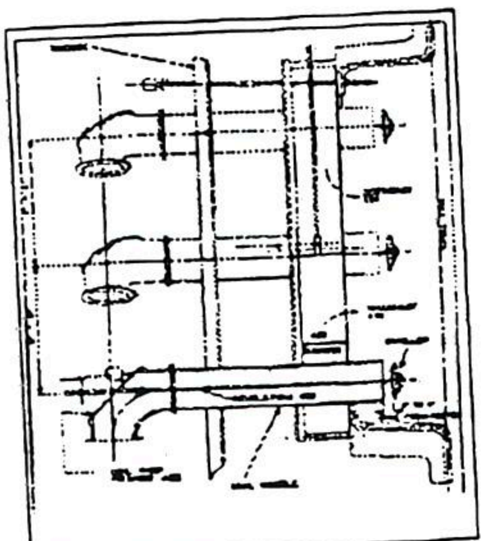

Figure 4

Several utilities have had easily converted two cell burner units to wall fired units. The difference between two cell burners and three burners is significant since the amount of space available for spreading out the burners among the available space is lower. This is because the spacing between burner cells is

[6] Progress Report, NOx Emission Reduction Study, B&W, December 22, 1992.

greater then the individual burners. A typical two-cell furnace would typically occupy more horizontal space than those of a comparable three-cell burner like H.A. Wagner Unit 3. In addition two cell burners can be easily retrofitted with a combined over-fire air port and low NOx burner (figure 5).

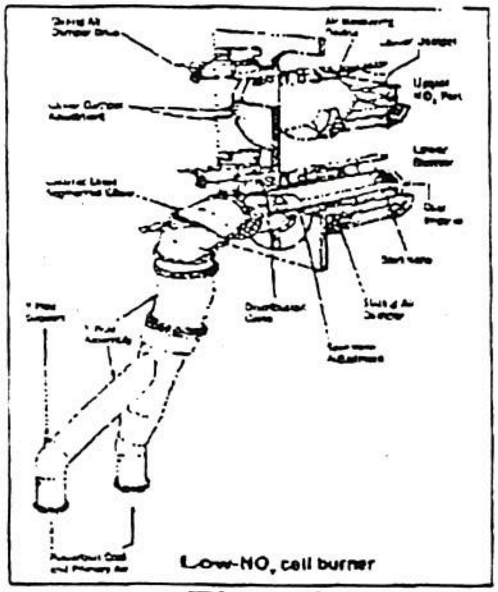

Figure 5

In addition to the space constraints on cell burners H.A. Wagner Unit 3's retrofitted boiler is different from that of a wall fired boiler in that the heat input per unit area is higher. Wagner 3's original cell burner design consisted of 36 burners. As a result of the retrofit, the new design has 24 burners. This decrease in the number of burners has increased the heat input for each burner. Compared to a wall fired unit, the heat input from these burners is typically higher and coupled with the effect of tighter horizontal spacing increases the difficulty of reducing NOx emissions.

H.A. Wagner Unit 4

Unit 4 at H.A. Wagner is a wall-fired 400 MW B&W designed No. 6 oil fired boiler. This unit has no additional NOx controls, but is a cycling unit that typically has a lower capacity factor compared to CPSO's coal-fired plants.

Riverside Unit 4

Riverside Unit 4 is a 80 MW natural gas boiler designed by B&W. No additional NOx controls were added due to natural gas firing and low capacity factor of the unit.

Gould Street Unit 3

Gould Street Unit 3 is a front wall-fired 105 MW, B&W designed dual fuel unit capable of firing either natural gas or No. 6 oil. The unit has low NOx burners installed in 1996 when natural gas firing was added for dual fuel capability.

Averaging Plan

As allowed by EPA, CPSG proposes to use an averaging plan to show compliance with the proposed NOx RACT requirements. This averaging plan will include the following CPSG units, Brandon Shores Unit 1 & 2, C.P. Crane Units 1&2, Gould Street Unit 3, H.A. Wagner Units 1 through 4, and Riverside Unit 4. Since individual unit compliance with the existing NOx RACT requirements is determined daily by a 30 day rolling average, CPSG's proposed emission averaging plan will also show compliance on a daily basis. Compliance will be demonstrated by showing that aggregate mass emissions from the averaging plan will be less than the units' mass emissions that would have been allowed on an individual basis.

As discussed above, CPSG's emissions will be less than NOx RACT requirements with the proposed averaging plan. As shown in Table 5, the effect of the averaging plan, based on 1999's heat inputs and emission rates, is an overall reduction in NOx emissions. In this case, NOx emissions under the averaging plan were over 4,000 tons lower compared with the emissions from compliance with the individual limits. The majority of the reductions were accomplished by over-controlling NOx emissions at H.A. Wagner Unit 3 and the Brandon Shores Units 1&2.

Table 5
NOx RACT Comparison of Individual NOx RACT limits Vs. Emissions Averaging.

Unit	Individual Limits		Emissions Averaging	
	Limit, lb/mmbtu	Tons	1999 Rate, lb/mmbtu	1999, Tons
Brandon Shores Unit 1	0.5	12,350	0.42	10,476
Brandon Shores Unit 2	0.5	12,979	0.46	12,056
C.P. Crane Unit 1	0.7 / 1.5	6,073	1.05	6,020
C.P. Crane Unit 2	0.7 / 1.5	8,773	1.03	8,117
Gould Street Unit 3	0.3	201	0.18	136
H.A. Wagner Unit 1	0.3	613	0.17	492
H.A. Wagner Unit 2	0.5	2,475	0.52	2,717
H.A. Wagner Unit 3	0.6	5,022	0.39	3,318
H.A. Wagner Unit 4	0.3	1,709	0.39	2,579
Riverside Unit 4	0.3	85	0.28	73
Totals		50,278		45,984

CPSG proposes to show daily compliance of CPSG's emissions averaging plan by showing, on a daily basis, that the mass emissions for the units in the averaging plan is less than the mass emissions rate allowed under individual unit NOx RACT limits. This following methodology will be used to determine compliance:

1. Calculate daily system and NO_x RACT emission rates

$$ER_{System} = \sum_{i=1}^{10} (ER_i * (HI_i/HI_{total}))$$

$$ER_{RACT} = \sum_{i=1}^{10} (ER_{RACT,i} * (HI_i/HI_{total}))$$

where;

ER_{System}	=	System average emission rate, lb/mmbtu
ER_{RACT}	=	System average NO_x RACT limit, lb/mmbtu
ER_i	=	Daily emission rate for unit i, lb/mmbtu
$ER_{RACT,i}$	=	Daily NO_x RACT limit for unit i, lb/mmbtu
HI_i	=	Daily heat input for unit i, mmbtu
HI_{total}	=	ΣHI_i, mmbtu

2. After 30 days calculate 30 day rolling emission rate for the system and the NO_x RACT limit,

$$ER_{30day\ System} = (\sum_{i=1}^{30} ER_{System}) / 30$$

$$ER_{30\ day\ RACT} = (\sum_{i=1}^{30} ER_{RACT}) / 30)$$

where;

$ER_{30\ day\ System}$	=	30 day rolling system average emission rate, lb/mmbtu
$ER_{30\ day\ RACT}$	=	30 day rolling system average NO_x RACT limit, lb/mmbtu

3. Calculate mass emissions on a daily basis

$$NOx_{System} = ER_{30day\ system} * HI_{total} / 2000$$

$$NOx_{RACT} = ER_{30day\ RACT} * HI_{total} / 2000$$

where;

NOx_{System} = NO_x mass emissions based on a 30 day rolling system average emission rate, tons

NOx_{RACT} = NO_x mass emissions based on a 30 day rolling average RACT limit, tons

4. Determine compliance with NO_x RACT,

$$NOx_{System} < NOx_{RACT}$$

Reporting

All ten units included in the averaging plan have continuos emissions monitors (CEM) for monitoring NOx emissions. These units follow the 40 CFR Part 75 requirements for all aspects of CEM operation, maintenance, recordkeeping, and reporting including missing data substitution. Quarterly reports will be submitted, within 30 days of the end of the reporting quarter, summarizing compliance with the averaging plan. In addition on a yearly basis CPSG will certify that the NOx mass emissions from the ten units included in the averaging plan are at least 5% less then allowed by the NOx RACT limits.

$$0.95 * NOx_{System\ Total} < NOx_{RACT\ Total}$$

where;

$NOx_{System\ Total}$ = Annual NO_x mass emissions for the ten units in the averaging plan

$NOx_{RACT\ Total}$ = Allowable NO_x mass emissions based on the NOx RACT limits

Summary

CPSG believes that the use of a NOx RACT emissions averaging plan meets both the intent of the NOx requirement and allows for CPSG to take the most economical approach to NOx RACT compliance. This proposal is also supported by EPA's EIP and similar averaging programs, such as the Title IV program, which also allows emission averaging as a compliance tool. It also provides an environmental benefit by achieving emission rates lowers then those without the averaging plan and will reduce NOx mass emissions at least 5% lower then allowed under the existing NOx RACT requirements.

Appendix "A"

BGE's July 1, 1993 C.P. Crane NOx RACT Proposal

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Appendix "B"

BGE's February 15, 1994 NOx RACT Proposal Summary

Appendix "A"

BGE's July 1, 1993 C.P. Crane NOx RACT Proposal

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NITROGEN OXIDES
REASONABLY AVAILABLE CONTROL TECHNOLOGY
PROPOSAL

BALTIMORE
GAS AND
ELECTRIC

CHARLES P. CRANE

UNITS 1 & 2

JULY 1, 1993

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INTRODUCTION

The Baltimore region has been designated a nonattainment area for ambient levels of ozone by the Environmental Protection Agency. The Clean Air Act as amended in 1990, requires states to develop and implement emission reduction plans which will lead to ozone levels below the health based standard. One of the requirements specified by Title I of the Act is for states to require the implementation of Reasonably Available Control Technology (RACT) at major sources by May 31, 1995. The Maryland Department of the Environment has promulgated regulations in the Code of Maryland Regulations (COMAR 26.11.09) to fulfill this requirement. Affected sources must submit RACT source by source proposals for approval. Three sites, with a total of six affected units, in Maryland must submit these proposals by July 1, 1993. This timing is based on related requirements contained in Title IV of the Act. Baltimore Gas and Electric has one site with two affected units which falls within this requirement. The Charles P. Crane Generating Station in Chase, near Essex, Maryland is the site of two 200 MW coal fired cyclone boilers. This proposal is submitted to fulfill this requirement. Similar proposals for the remainder of the Baltimore Gas and Electric system are required by November 15 of this year.

Baltimore Gas and Electric has worked closely with the Department of the Environment since early 1992 on the development of NO_X RACT regulations. This relationship has included technical support and participation in the Department's NO_X RACT plementation Work group. Department personnel are to be commended for their commitment to dialogue and for the openness in which the requirements have been developed. Air quality is our joint concern and strategies to improve it can best be accomplished with maximum interaction by those affected. We are hopeful that this beneficial interaction will continue until we reach our mutual goal of a cleaner environment.

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I. BACKGROUND

A. Facility Description

Charles P. Crane Station is located east of Baltimore on Seneca Creek near Chase, Maryland. The plant's location is depicted in Appendix C.

Crane Unit 1

Unit 1 at Baltimore Gas & Electric's (BG&E) Crane Station is a coal fired balanced draft, Carolina, subcritical, cyclone fired Universal Pressure Boiler with single reheat. Unit 1 is designed to deliver steam to the turbine at 2400 psi and 1050°F at a flow of 452,000 lbs/hr to 1,357,000 lbs/hr. The reheat stage is designed for 1000°F steam temperature from 619,000 lbs/hr flow to 1,056,000 lbs/hr. The unit is equipped with four direct fired cyclones 10' in diameter, two in the front wall and two in the rear wall. The boiler had been originally equipped with gas recirculation (GR) and gas tempering systems.

Crane Unit 2

Unit 2 at Baltimore Gas & Electric's (BG&E) Crane Station is a parallel gas flow, cyclone fired, Carolina Radiant Boiler. Unit 2 is designed to produce a main steam flow of 1,360,000 lbs/hr at 2475 psig and 1050°F at the superheater outlet. The reheat stage is designed for 1,070,000 lbs/hr steam flow at 535

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g and 1000°F at the reheater outlet. These boilers were originally designed as pressure fired units.

The boilers are equipped with four 10'-0" diameter direct fired cyclones for coal firing. The cyclone arrangement consists of two cyclones on the front wall and two cyclones on the rear wall. The boiler was originally equipped with gas recirculation for partial load and gas tempering for full load operation, which have since been removed from service.

In 1983, each unit at Crane Station was modified to convert the existing boiler from pressurized to balanced draft. Material changes for the conversion to balanced draft included modifications to the boiler enclosure, air heaters and gas recirculation (GR) flues.

In 1988, heat pipe air heaters were installed on both Crane units. Subsequently, these heat pipe air heaters were removed and replaced with the conventional tubular air heaters.

Heat input for each unit was approximately 9.5×10^6 mmBTU in 1990. Average annual heat input over the next ten years is projected to be approximately 12.25×10^6 mmBTU/yr. These units are each designed to generate 190 megawatts net capacity.

B. Emissions Data

Both units at C.P. Crane are equipped with continuous emissions monitors which provide detailed NO_x emissions data as well as information on SO_2, CO, CO_2 and opacity. Present NO_x emissions levels for the Crane units are generally in the range of:

0.7 - 1.7 lbs/mmBTU for Unit No. 1

0.9 - 1.8 lbs/mmBTU for Unit No. 2

Appendix A shows NO_x data in various formats. Data used to depict NO_x emission is from the period of January 1 - May 14, 1993. These figures show the NO_x vs. Load profiles for each unit as well as NO_x and Load distributions.

Appendix B is a tabular representation of actual NO_x emissions data from C.P. Crane Units 1 & 2.

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ONTROL TECHNOLOGY

. INTRODUCTION

Emissions of nitrogen oxides (NO_x) from combustion of fossil uels can react in the atmosphere and result in photochemical mog, as well as contribute to acidification of lakes resulting n damage to aquatic life and vegetation. Environmental concerns ave resulted in regulations to limit NO_x emissions from stationary sources, including boilers. Consequently, NO_x control measures are required for new sources and some existing sources in order to satisfy these regulations.

NO_x is formed during combustion of fossil fuels by several nisms. At flame temperatures in excess of 2800°F, significant quantities of so-called thermal NO_x are formed by dissociation and oxidation of nitrogen from the combustion air. Thermal NO_x is the primary cause of NO_x from firing natural gas, and a major contributor with fuel oil. Fuel NO_x refers to emissions which result from oxidation of nitrogen which is bonded to the fuel molecules. This nitrogen becomes actively involved in the combustion process as hydrocarbon chains are broken and oxidized, and a portion of the fuel nitrogen is oxidized as a result. Fuel bound nitrogen is found to varying degrees in heavier fuel oils (and coal), but is insignificant in light oil (No. 2) and natural gas. Fuel NO_x is the primary cause of NO_x om pulverized coal. Heavy fuel oil also has high quantities of uel bound nitrogen, which results in increased levels of fuel

Prompt NO_x refers to emissions formed during combustion from hydrocarbon radicals dissociating atmospheric nitrogen, followed by oxidation. Prompt NO_x plays a minor role in overall NO_x production with fossil fuels.

Several methods are available to effectively limit NO_x formation during combustion. The combustion system design will depend upon the capacity and fuels to be fired, as well as the requirements to limit NO_x emissions. Thermal NO_x can be controlled by reducing the thermal loading to the combustion zone. Mechanisms include increasing the size of the combustion zone for a given thermal input; reducing the rate of combustion and peak flame temperatures by burner design; and addition of circulated flue gas to the combustion air to depress flame temperature. Fuel NO_x can be controlled by limiting oxygen availability during early phases of combustion. Mechanisms include reducing excess air; reducing burner stoichiometry by removing a portion of the combustion air from the burner and introducing this air later through air staging; and by burner designs which limit the rate of air that is introduced to the fuel early in the flame.

Peak NO_x levels tend to occur early in the combustion process as flame temperatures peak and while oxygen availability is the highest, whether or not countermeasures are employed. The NO_x formed early in the process can be reduced downstream by use of fuel staging principles. Fuel staging involves introduction of fuel downstream of the flame under fuel rich conditions.

drocarbon radicals are thus formed which attach to the NO_x molecules, resulting in NO_x destruction.

Fuel staging can be accomplished by fuel staging burners located downstream of the main burners and in combination with air staging ports; or by a burner design to accomplish these effects by fuel injection/air flow patterns.

B. CONTROL METHODS

The C.P. Crane facility is different from all other Maryland coal fired utility boilers in that it consists of cyclone fired furnaces. Typically, the cyclones burn very hot which results in high levels of uncontrolled NO_x emissions. A cyclone furnace consists of a cyclone burner connected to a horizontal water cooled cylinder, commonly referred to as the cyclone barrel. Air and crushed coal are introduced through the cyclone burner into the barrel. The larger coal particles are thrust to the barrel walls where they are captured and burned in the molten slag layer which is formed. The finer particles will burn in suspension. The mineral matter melts, exits the cyclone from the tap at the cyclone throat and is dropped in a water filled slag tank. The flue gases and remaining ash leave the cyclone and enter the main furnace. Some of the advantages of cyclone firing include: 1) reduction in flyash content in the flue gas; 2) savings in the cost of fuel preparation, since only crushing is required instead of pulverization; and 3) reduction in furnace size.

Presently, 100 plus operating cyclone-equipped boilers xist, representing about 13% (over 25,000 mW) of pre-New Source 'erformance Standards 1971 (NSPS) coal-fired generating capacity. Iowever, these units contributed approximately 21% of the NO_x emitted since their turbulent, high-temperature combustion process is conducive to NO_x formation.

Due to boiler configuration and operation, low NO_x burner technology is not applicable to the cyclone design. In addition, operational adjustments, such as low excess air or modification to include overfire air, cannot be considered due to minimum furnace design requirements. Overfire air is not applicable to cyclone boilers because combustion staging will significantly er the heat release profile which changes the slagging rates d properties of the slag. There are currently no economical, commercially demonstrated, combustion modification techniques that exist for cyclone equipped boilers to reduce NO_x emissions. However, the reburning technology, the only known combustion control for cyclone boilers, offers cyclone operators a promising alternative to reduce NO_x emissions. Both gas and coal reburning are in the developmental state, with few demonstrations in progress to determine commercial feasibility. However, long term testing is required to adequately address control performance, operational impacts, and commercial feasibility.

Post combustion technology also holds promise for NO_x eductions in the realm of long-term attainment. In the forefront at this point are selective catalytic and selective catalytic reduction. However, for first round NO_x reductions, it has been shown that combustion modifications are available for wall and tangentially fired and have the potential to provide the cost effective NO_x emissions reductions at stationary fuel combustion sources. Based on this information, determination has been made that affected parties will proceed with development of regulations related to RACT requirements based on combustion modifications for implementation in 1995.[1]

C. INDUSTRY EXPERIENCE

Reburning or fuel staging has been identified as the only [combu]stion control technique for cyclone fired boilers. Demonstrations are underway to evaluate the retrofit potential and control performance of reburning on five utility boilers, three of which are cyclones:

- Ohio Edison, Niles 1, 120 MW, gas reburn.
- Wisconsin Power & Light, Dewey 2, 100 MW, coal reburn.
- City Water Light & Power, Lakeside, 40 MW, gas reburn.

Niles

A full scale demonstration of gas reburning on a cyclone boiler was completed in July 1992 at Ohio Edison Company's Niles Unit No. 1. Analysis of the long-term performance test data indicates that 45% NO_x reduction from baseline levels was possible at full load. NO_x reduction significantly decreased with decreasing load; only 33% NO_x reduction from baseline levels was demonstrated at 75% load. NO_x reductions were not possible at this site below 75% load, because the cyclone could not be operated at a low enough firing rate to direct heat input to the reburn zone without creating slag tapping problems (i.e. inability to maintain sufficiently high temperatures in the ~~clones~~ cyclones to keep the slag fluid). NO_x reductions were achieved at practical levels of reburn zone stoichiometry (e.g. nominally 0.95).

Gas reburn can induce a thermal efficiency penalty, because the higher fuel hydrogen/carbon ratio of gas relative to coal increases flue gas water content (e.g. higher latent heat losses, or "thermal waste"). At full-load, boiler efficiency decreased by approximately one percentage point. The demonstration showed that CO emissions can significantly increase with implementation of reburning, but can be restored to acceptable levels if process optimization is possible. For the Niles Station the process could be optimized to reduce CO; but boilers of larger generating capacity with greater distances over which to mix fuel and air may pose CO problems. The principal disadvantages of natural gas the reburning fuel are that it carries a significant fuel cost differential penalty, and it may not be economically feasible as RACT.

This project was a demonstration sponsored by the Gas Research Institute, EPA, DOE, and the Ohio Coal Development Office. Funding was eventually exhausted and the system removed. Reasons for removal beyond funding included prohibitive natural gas prices and system equipment quality at that location.

Dewey

A demonstration of coal-reburning is presently in progress cyclone boiler at Wisconsin Power & Light's Nelson Dewey Station. The results, obtained from short-term testing from a relatively small capacity (110 MW) cyclone boiler, show approximately 50% NO_x removal is possible. As with the gas reburn results at Niles, NO_x reduction levels decreased to 35% at low loads. These results are preliminary, and are not complete without a characterization of fly ash carbon content and CO. Initial observations suggest small fly ash loss on ignition (LOI) increases, but definitive results are not available at present.

Unlike gas reburning, coal-reburning does not degrade thermal efficiency from changes in fuel hydrogen/carbon content. However, depending on the heat biased from the furnace to the convective section, a thermal efficiency penalty can accrue. For le, the thermal efficiency penalty at Nelson Dewey is timated to be less than 1%.

Lakeside

The final reburn demonstration is at Lakeside Station at ity Water, Light & Power. This is a 40 MW capacity cyclone oiler utilizing natural gas as the reburn fuel. Construction as recently been completed and testing is underway.

In summary, these initial tests have shown that reburning has the potential to be an effective control technology. F ver, long-term testing remains to adequately address control ormance, operational impacts, and commercial feasibility. Furthermore, application of this control technology is highly site specific with achieved results not necessarily transferrable between facilities.

D. ATTAINMENT REDUCTION METHODOLOGY

Beyond RACT in 1995, further NO_x reduction may be required to bring this area into attainment of the National Ambient Air Quality Standards by 2005. In that time frame, it is believed that the reburn technology may be both commercially available and hnically proven. Post combustion technologies will also be nsidered for NO_x control beyond the first round reduction based

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Conclusion

BGE's system NO_x emissions are already low, with nearly half of its yearly generation coming from non-NO_x emitting sources. In addition, one-third of the generation comes from a plant with NO_x-limiting equipment already in place.

Further emission reductions have been proposed as RACT on our Wagner coal-fired units. Some units produce minor emissions and are beyond RACT. Seasonal fuel-switching on other units will also reduce NO_x emissions. The six units recently removed from service will yield further reductions in NO_x and other emissions.

All of these measures will serve to keep BGE emissions well within NOX emissions standards. BGE is committed to working with the Maryland Department of the Environment if additional control strategies become necessary.

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nit.

BGE has begun to look at measures beyond RACT that have the potential to reduce NO_x emissions further. As a result of our initial analysis, BGE is willing to commit immediately to seasonal fuel switching on two units, providing additional reductions as part of this proposal. H. A. Wagner Unit 1, a 137 MW electric generating unit, will use natural gas for a minimum of 70% of its total heat input during the ozone season beginning in 1995. Riverside Unit 4, a 78 MW electric generating unit, will provide 100% of its generation during the ozone season through the combustion of natural gas beginning with the 1994 one season.

In addition to our RACT reductions, six generating units were removed from service over the last two years which will provide additional environmental benefits. These benefits include a 3,000-ton reduction in NO_x since the 1990 baseline year as well as major reductions in other regulated pollutants. Sulfur dioxide from these facilities will be reduced by more than 6,000 tons annually over the baseline year. Annual particulate and carbon monoxide emissions will be reduced by more than 200 tons each. And volatile organic compounds, another ozone precursor, will be reduced by approximately 30 tons annually. Furthermore, advanced dry low-NO_x combustor technology will be employed to limit NO_x emissions at BGE's new Perryman unit under construction in Harford County.

Other Plants

Ten oil and oil/natural gas-fired steam generating units operated during the baseline period. Nine are listed in the table following this summary. Riverside Unit 1 is excluded because it was retired in late 1991. Since that time, five more units have been removed from service. The lack of NO_x control technology and the minor emissions rates of these units have resulted in the conclusion that equipment-based RACT is not available for these units. Operation and maintenance procedures for operational parameters related to the level of NO_x emissions will be developed in conjunction with the MDE if required for RACT.

Although new combustion turbine units can be fitted with NO_x-limiting combustors, NO_x emission control for existing combustion turbines is generally limited to water or steam injection, which are prohibitively expensive and beyond RACT requirements.

No additional RACT is proposed for the remaining equipment covered in the proposal. Analysis revealed only one site with significant enough operating time to warrant a RACT proposal. Two small (100 HP) internal combustion engines are used to provide peak-period electricity and hot water to a hotel in Baltimore County. This installation employs a lean-burn design and ignition retard to control NO_x. These measures were installed of our total NO_x emissions are generated from coal-fired units, which have inherently higher emission rates than other fuels.

BGE generally proposes to work with the MDE to develop minimum operation and maintenance procedures for NO_x control on equipment with significant actual emissions of NO_x. Following is a description of proposed measures for BGE's most significant NO_x sources.

Brandon Shores

As noted, low-NO_x burners were incorporated at Brandon Shores during construction. Because of this equipment, these units operate at 30% below their NO_x standard. This equipment is RACT for the unit.

Wagner

Units 2 and 3 at the Wagner generating station are coal-fired. Emissions and control options have been examined and we will install low-NO_x burners to meet the RACT requirement for Unit 2. Unit 3 uses a three-cell burner design, while most cell burners are two-cell in design. Since there is no technology that can be applied to this design, RACT does not include combustion modification for this unit.

Units subject to Phase I of Title IV of the Clean Air Act are required to submit their proposals by July 1, 1993. BGE met this requirement, which covered the major units at its C. P. Crane station.

Proposal

This proposal covers the remainder of BGE's system. Although 19 sites have equipment with an estimated potential to emit above the 25-ton NO_x threshold, only nine of these will ever actually exceed the threshold. The remaining sources are mostly equipment that rarely operate since they supply only short-term emergency needs.

BGE's system air pollutant emissions are extremely low. This emission rate is illustrated in the 1992 equipment and NO_x emissions table following this summary. The information presented is based on our best estimates of emissions, using limited test data, EPA emission factors, and, where applicable, continuous emission monitoring data. Our low rate is due to two primary factors. Foremost, electricity generation from sources with zero NO_x emissions approaches half of the company's generation for a typical year. Second, our Brandon Shores plant, which contributes about a third of our electricity, has had NO_x-limiting equipment in place since beginning operation.

The table following this summary illustrates the fact that BGE NO_x emissions are almost exclusively a product of fossil-fuel-fired electrical generating units. Furthermore, well over llable to the EPA to hold states to schedules contain an 18-month window for application.

Title IV of the Act contains requirements, which are to be developed by EPA as a national program, for utility fossil-fuel-fired generating units. These requirements, while not fully promulgated, will require "low-NO_x burner (LNB) technology." The goal of this program is to reduce annual NO_x emissions two million tons nationally. Wall and tangentially fired units, which are affected as Phase I units, must meet the presumptive limits of 0.5 and 0.45 NO_x lb/mmBTU heat input, respectively. The EPA has estimated the cost of these requirements at about $200 per ton. If the presumptive rates cannot be achieved through LNB technology, provisions for establishing an ernative emission limit (AEL) can be used to establish an appropriate unit-specific limit. Presumptive rates for other coal-fired furnace designs, including cyclone and cell burners, and Phase II units will be established in 1997.

The state of Maryland has promulgated regulations at COMAR 26.11.09 to implement the RACT requirement. Sites with the potential to emit 25 tons of NO_x emissions must either:

1. Demonstrate that the equipment operates below a listed standard, or

2. Propose a RACT.

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kground

Title I of the Act mandates the control of VOCs and NO_x. The levels of control required for VOCs are specifically mandated. The state of Maryland must develop a plan to reduce the state's VOC emissions a minimum of 15% by 1996. Thereafter, the state must reduce VOCs at least 3% per year until attainment is reached. NO_x control requirements are less prescriptive. Maryland must require the installation of "reasonable available control technology" (RACT) for control of NO_x emissions on large stationary sources. This is a technology requirement designed for early, easy-to-achieve reductions and is the subject of this proposal.

In addition to RACT requirements on large stationary sources ... emissions, there are mandated and optional programs for control of VOCs and NO_x from mobile sources. By November 15, 1994, Maryland must present to the Environmental Protection Agency (EPA) an air-quality control plan for attainment. This plan must list specific measures to reach attainment and include a computerized atmospheric modeling demonstration showing the plan will work. The modeling exercise must predict the outcome of control measures before they are implemented. The Maryland Department of the Environment (MDE) is in the preliminary stages of this modeling demonstration. Note that EPA's and MDE's resource limitations have frequently resulted in late submittals for established deadlines. Furthermore, Clean Air Act sanctions

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EXECUTIVE SUMMARY

Introduction

The Clean Air Act (the Act) as amended in 1990 establishes air pollution control requirements for states in areas where the ground-level ozone concentration is above the national standard. These areas are called "nonattainment areas" for ozone. Maryland has several nonattainment areas, including the Baltimore metropolitan area.

Nitrogen oxides (NO_x), along with volatile organic compounds (VOCs), have been identified as precursors to the formation of elevated ambient levels of ground-level ozone. Nitrogen oxides are formed primarily through combustion of fossil fuels. VOCs are formed through a variety of mechanisms and are most frequently encountered as evaporating vapors from solvents and gasoline.

As a large utility that relies on combustion of fossil fuels for much of the electricity it generates, Baltimore Gas and Electric (BGE), like any similar utility, is a major source of nitrogen oxide emissions. BGE's rate of emissions, however, is much lower than utilities with only fossil-fuel-derived generation. Non-emitting sources of electricity, including Calvert Cliffs and Safe Harbor, provide BGE with a system NO_x emission rate of 0.32 pounds per million British Thermal Unit (lb/mmBTU) heat input. Few other utilities with significant fossil-based generation have comparable rates.

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NITROGEN OXIDES

REASONABLY AVAILABLE CONTROL TECHNOLOGY

PROPOSAL

BALTIMORE
GAS AND
ELECTRIC

FEBRUARY 15th, 1994

Appendix "B"

BGE's February 15, 1994 NOx RACT Proposal Summary

which was test burned in 1992, may provide an approximate reduction of 5% in NO_x emissions. The potential has only been identified with one specific coal and supplier. We are currently looking at the price and supply reliability of this coal, along with competing varieties. Any new fuel selected would have to be on site in late 1994, with the transition from the existing coal to be completed early in 1995, to meet our sulfur dioxide emission plan. At that point, it is recommended that a new NO_x emission baseline be developed for the purposes of setting an emission standard.

I. RECOMMENDATION

Based on the discussion in this report and the past history of equipment modifications at C.P. Crane, it is recommended that no combustion modifications for May, 1995 be considered RACT for these units. Optimum combustion conditions for these cyclone boilers have been achieved over the past two and one-half years, with complete plant control system and coal feed system equipment replacements. These changes have allowed considerable improvements in fuel flow measurement accuracy and fuel air flow balancing and control, with the result being conditions of greatest combustion efficiency and minimum NO_x production.

To maintain cyclone performance, unit outage schedules have been optimized over the years to prevent significant equipment degradation. This cycle is currently 12-18 months. In addition, personnel receive both the technical and operational training to obtain peak performance from these units. If there have been any enhancement opportunities identified during the RACT determination process, it has been with the knowledge of NO_x formation, emissions data, and the requirements of the Clean Air Act Amendments of 1990. The Baltimore Gas and Electric Company will provide training to personnel from all electric generating stations for the purpose of education in these areas.

BG&E has identified the potential for sizeable NO_x emissions reductions as the result of a contemplated fuel switch. The lower nitrogen, high fuel ratio (fixed carbon to volatile) coal

The average NO_x emission before and after the test burn is 1.35 lb/mmBTU which approximates the current yearly average of 1.34 lb/mmBTU for 1993. Based on the lower 1993 average, a switch to this low sulfur, low nitrogen, high fuel ratio coal would provide a NO_x reduction of 6.7% for C. P. Crane. Based on 1990 inventory and projections from 2000, this translates to between 800 and 1000 tons/year of NO_x reduction from C.P. Crane Station. Modifications required to allow burning of this coal on a full time basis is estimated to be $6.4 million, 40% of which may have been instituted regardless of the fuel switch.

`. EMISSIONS VARIABILITY

The resulting effect of this low sulfur, low nitrogen, high fuel ratio coal on emission rate is undeterminable due to the high variability of NO_x emission data. A discussion of the effects of this variability is contained in Appendix F. Obviously, a longer baseline of emission data is necessary prior to establishment of a standard.

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bound nitrogen is consistently below the nitrogen levels of the fuel currently used. Fuel ratio is similarly beneficial. Comparisons are shown in the table below.

	EXISTING COAL	PROPOSED COAL
N_2 Content (%)	1.31	1.19
Fuel Ratio (FC/VM)	1.31	3.56

These beneficial characteristics were considered in the formulation of the proposed switch to this coal. In April, 1992, test burn of this coal was performed at this facility for the purpose of determining SO_2 reductions and plant coal handling capability. A report of this test burn is included in Appendix G. NO_x emissions for that period were recorded for Unit No. 2 on the continuous emissions monitors (CEM). The following is an analysis of NO_x emissions data since the installation of the CEM: All CEM data can be found in Appendix B.

- Average NO_x emission prior to the test burn was 1.45 lb/mmBTU
- Average NO_x emission during the test burn was 1.25 lb/mmBTU
- Average NO_x emission for a period after the test equivalent to the period of the test was 1.32 lb/mmBTU
- Average NO_x emissions for 1993 to date is 1.34 lb/mmBTU

el cost differentials would approach $10 to $12 million dollars per year per unit based on projected heat inputs, and thermal efficiency penalties would be approximately $1,000,000 per year per unit. When modification costs are factored in along with a generous assumption of 50% NO_x reductions, cost effectiveness numbers approach the $5,000/ton mark.

An alternate fuel switch scenario has also been evaluated. It has been documented that switching coals to those with lower-nitrogen content and higher-fuel ratio (fixed carbon to volatile matter) will reduce NO_x on previously uncontrolled units. As the nitrogen content in the fuel increases so does the overall NO_x level. Generally, only a fraction of the total fuel-bound nitrogen is converted to NO_x. That amount is usually in the range of 20 to 80 percent when combustion is not staged. The higher nitrogen fuels have lower conversion rates but higher overall NO_x emissions. Typically, under unstaged combustion conditions lower fuel ratios correlate with higher production of NO_x. This is the result of greater amount of volatile nitrogen released in the high temperature zone of the flame where sufficient oxygen is available to generate high levels of NO_x. When the combustion is staged, the effect is the opposite.

In July, 1992 BG&E submitted its Compliance Plan for Title IV of the 1990 Clean Air Act Amendments to the Public Service Commission. One compliance option proposed consisted of switching fuels from the existing coal to a low sulfur variety. In addition to the sulfur dioxide benefits of this fuel, the assified as reasonably available or technically proven, regardless of the economics.

The cost of a natural gas reburn system has been identified within the industry as between $25 and $50 per kilowatt. These numbers may look favorable at first glance. However, industry reports recognize, but fail to quantify, the costs outside the scope of equipment supply and installation. For those facilities such as C.P. Crane that do not currently have gas firing capability, pipeline construction costs as well as supplier pipeline reinforcement fees need to be considered. Fuel costs differentials also need to be addressed. At C.P. Crane, that ferential runs anywhere between $1.00 and $1.50 per mmBTU. pending on the ratio of coal to natural gas input, the cost varies, but is always considerable. Firing of natural gas at C.P. Crane will also create a boiler efficiency and heat rate loss of 1% to 2% which translates into added fuel costs and modified dispatch rates. These increased costs, coupled with the unavailability of this technology, eliminate natural gas reburn from consideration as RACT at C.P. Crane Station.

In addition to combustion modification for NO_x control, fuel switching scenarios were investigated. For some of the reasons stated above, a fuel switch to full load natural gas firing is not economically feasible as RACT. Pipeline costs and upfront pplier fees for C. P. Crane have been estimated to be in the $25 to $35 million range. On top of that, a monthly supplier fee of $80,000 - $100,000 may be required to guarantee fuel delivery.

RACT DETERMINATION

A. RACT

The EPA has defined RACT (Reasonably Available Control Technology) as the lowest emissions limitation that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility. The Ozone Transport Commission has concluded that significant stationary sources of NO_x will implement, by May 1995, combustion modifications based on RACT criteria. It has been well documented that the only combustion ification technique applicable to cyclone boilers is reburn echnology. At C.P. Crane, natural gas reburn is the only option because of the boiler design. All other combustion modifications that are available today such as low NO_x burners, overfire air, low excess air, and burners out of service are not technically acceptable options for cyclone fired boilers.

Even though there is promise in natural gas reburn for NO_x emission reduction, is it clearly considered to be in the demonstration phase. There have only been two full scale implementations. One has been completed and discontinued for a number of reasons including the cost prohibitiveness of natural gas. The other has just completed construction and is in the esting phase. Natural gas reburn can therefore, neither be

RACT criteria. A summary on the applicability of these echnologies for NO_x reduction beyond RACT is included in ppendix E.